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Effects of large-scale power to gas conversion on the power, gas and carbon sectors and their interactions

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Abstract

The increasing share of intermittent renewable electricity production leads to operational challenges in the electric power sector. Storage will be needed, among other options, to ensure an efficient and reliable operation of the electric power system. The power to gas (PtG) concept provides a possibility to store excess renewable electric power and as such it can increase the utilisation of RES-based electricity generation. The renewable methane, produced via PtG, can be stored in the gas system and used e.g. for electricity generation. The gas system has a much larger storage capacity compared to current electricity storage technologies. However, PtG introduces extra couplings between the gas, electricity and carbon (CO_2) sector and it is not known what the effect of these new interactions could be. Therefore, an operational model has been developed that includes the gas, electricity and CO_2 sector to analyse the effects of PtG on these sectors and on the interactions between them. Based on a case study, it is found that PtG partially transfers capacity and flexibility problems, triggered by the introduction of intermittent RES-based electricity generation, from the electricity to the gas sector. Moreover, a downward pressure on the gas prices is observed. However, the effects of PtG are generally smaller than those

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of the large-scale introduction of intermittent renewable electricity generation. Also, complex inter-sector dependencies are introduced through the CO_2 that is required in the PtG process. If PtG is to be deployed at large scale, the study of these effects is relevant for policy makers, regulators, energy markets' participants and system operators.

Keywords: Power to gas (PtG), system integration, system interactions, CO_2, Renewables

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Nomenclature

CAES	compressed air energy storage
CC	carbon capturing (plants)
GFPP	gas-fired (electric) power plants
LNG	liquefied natural gas
MCC	marginal carbon cost
MEC	marginal electricity cost
MGC	marginal gas cost
MILP	mixed-integer linear programming
NOH	number of operating hours
$O\&M$	operation and maintenance
PHES	pumped hydro energy storage
PtG	power to gas
PV	photovoltaic
RES	renewable energy sources
RM	renewable methane
TSO	transmission system operator

1. Introduction

The share of renewable electricity generation has increased steadily over the past years, and the current trends and energy pathways indicate a further increase [1]. However, the variability and limited predictability of electric renewable energy sources (RES) result in new operational challenges for electric power system operators in maintaining the system balance [2]. Advanced operational techniques will be needed, amongst other options, such as storage, to ensure a safe and reliable operation of the electric power system [3, 4].

Several (indirect) electricity storage options exist, such as pumped hydro electricity storage (PHES), compressed air energy storage (CAES), flywheels and batteries [5, 6, 7, 8]. These current storage technologies generally have a limited energy density (e.g. batteries) or storage potential (e.g. PHES) [9, 10]. PHES may provide a large-scale storage option, but the number of countries where such large-scale PHES is possible are limited. An interesting, possible electricity storage option is the 'power to gas' (PtG) concept that converts excess electricity into hydrogen or methane that can be injected in the gas network and be used later on, e.g. for electricity production [11]. The gas system, which often includes large-scale gas storage, as such allows storing significant amounts of renewable energy, contributing to the integration of intermittent RES. Moreover, the gas system may play an important role in the future energy system due to, among other elements, its robustness, its proven reliability and the required backup of intermittent renewable electricity generation that can be provided by flexible gas-fired power plants [12, 13, 14]. Therefore, natural gas, its assets and gas-fired electricity generation are considered as available in the intermediate time horizon in the transition towards a sustainable low- carbon energy system. Furthermore, gas-fired power plants provide a potential source of CO_2, which is a required input product of the PtG process.

This PtG process consists of two steps [11]. The first step is the conversion of (renewable excess) electricity and water into hydrogen and pure oxygen. The hereby produced renewable hydrogen could be directly injected in the gas network. However, the possible share of hydrogen in the natural gas network is limited [15]. The second step in the PtG process is the conversion of hydrogen and CO_2 into renewable methane (and water). Renewable methane can be injected in the natural gas network without limitations if the natural gas has a high calorific value. In this work, only the entire conversion process of electricity to renewable methane is considered. However, it must be noted that the PtG technology is currently still in development: field tests are limited to demonstration plants [16].

However, it is important to study the effects of the introduction of large-scale PtG conversion in the energy system, especially because it creates alternative linkages between the gas, electricity and CO_2 sector. The relevance of system integration studies has already been well demonstrated in the electricity sector where the introduction of intermittent RES-based generation may trigger adequacy issues due to flawed market designs [17]. Also, the gas sector can be affected by the integration of intermittent renewable electricity generation. Particularly relevant for this paper are the conclusions of [14] where the impact of wind generation on the gas system is studied. It is found there that because of wind, gas transport related costs will increase the unit price of gas due to lowered utilisation of the gas network transport capacity. Furthermore, the demand for flexible gas supplies increases due to the increased gas demand spread and limited wind predictability, and this could be mitigated to a certain degree by, e.g., a liquid spot market, increased gas storage and LNG (liquefied natural gas) terminals [14].

Therefore, the aim of this paper is to analyse the impact of the introduction of PtG on the gas, electricity and CO_2 sector. Furthermore, the operational effects of PtG on the interactions between the different sectors will be studied: The main research questions in this paper are:

- What are the operational effects of PtG on the gas sector? More specifically, what are the operational effects on the gas import profile and on the demand for gas flexibility and what could be the long-term impact of those effects on gas capacity and flexibility costs? What are the effects on the capacity requirements for the gas network and seasonal gas storage?

- What are the effects on electricity sector? More specifically, what is the impact on the marginal electricity cost?

- How much CO_2 is required to 'fuel' the PtG process? How much CO_2 storage is required?

Furthermore, we will describe the operational effects of PtG on the interactions between the different sectors. The focus of the research is on operational short-term effects. However, these effects will be looked at in a case study over a whole year, yielding indications of longer-term effects of PtG. The presented case study reflects an energy system with a high RES penetration and PtG. This case study should be seen as a possible, or rather a hypothetical, future energy scenario as PtG technology is currently not available at large scales. As there are many uncertainties regarding the technologies and the costs of a system with PtG, the main focus of the analysis is on qualitative effects, rather than claiming quantitative effects.

As will be illustrated in the results, the introduction of PtG may have a considerable impact. Most notably, PtG may increase gas system capacity and flexibility related costs. It may also have a downward pressure on the gas prices, which is in line with the findings of [14] related to the impact of wind in the energy system. Furthermore, the alternative links between the different sectors in the energy system, introduced by PtG, create complex inter-sector linkages through the CO_2 that is required in the PtG process.

The remainder of this paper is organised as follows. Firstly, the approach is discussed, giving the model layout and useful models of subsystems in the literature. Secondly, the case study is elucidated and the methodology is given to determine the installed power to gas capacity in a given energy system. Thirdly, the results are analysed. The results are discussed per sector, for both the long- and the short-term effects. Also, the effects of power to gas on the interactions between the different sectors in the energy system are analysed. At last, the main conclusions are formulated, together with suggestions for further work on this topic.

2. Approach

An operational model of the considered energy system is set up using mixed-integer linear programming (MILP), based on [18] and it is available in full detail in [19]. The energy system is comprised of the gas, the electricity and the CO_2 sector. Additionally, PtG plants are part of the model (Fig. 1). The energy system is modelled as one single system, in which the demand for each energy carrier has to be satisfied at minimal cost within the techno-economic limits of the subsystems, e.g. the operational limits of the power plants.

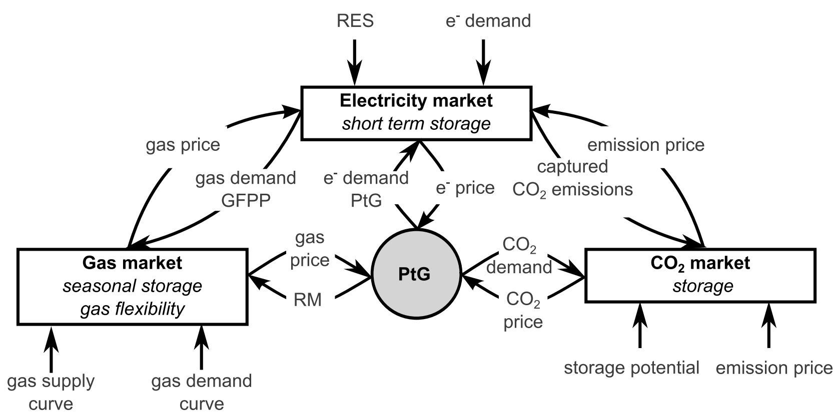


Figure 1: Illustration of the interactions in the model between the gas, electricity and CO_2 sectors. Power to gas (PtG) makes up an alternative coupling between these sectors. GFPP stands for gas-fired (electric) power generation, RM for renewable methane, RES for renewable electricity sources and e^- for electricity.

The presented model has been largely based on existing models available in the literature (Subsection 2.1). Secondly, a general description of the used model is given. More information on the model, the assumptions and the implementation is given in [19].

2.1. Available modelling frameworks in the literature

The model used in this paper did not need to be built from scratch; it has been largely based on operational models that are available in the literature for subsystems of the energy system at hand. Electric power plants are required in the model to enable the analysis of the impact of PtG on the electric power sector. Useful operational models for electric power plant dispatch optimisation are available. The reference model formulation that has been used here can be found in [18]. Also, the gas sector should be included in the model, to be able the assess the impact of PtG on the flexibility demand, the import profile and seasonal storage. Several formulations of aspects in the gas value chain can be found in [20], which includes the optimisation of transport, storage, portfolio management, economic dispatch and network modelling. Additionally, useful insights and modelling techniques related to gas flexibility can be found in [21]. Specific formulations for PtG plants have been built, based on similarities with electric power plants and their representation in operational models. In this paper, PtG plants have been modelled as black box models, based on current and projected characteristics of the technology as in [11, 9, 22]. A more advanced model, representing the different steps of the power to gas process individually, is available in [23]. However, such detailed description of the internal process is out of scope here and would make the simulation model computationally too difficult to solve. Furthermore, it is assumed that all CO_2, needed for the PtG process, is available from carbon capturing (CC) in the electric power sector. However, CC is not a mature technology [24]. Operational aspects have been studied through simulations models but practical experience is limited to pilot plants [25]. In this paper, we assume the availability of a mature CC technology. It should be stressed that, although based on available knowledge of small-scale pilot plants, the PtG and CC plant models are hypothetical and represent large-scale facilities. In conclusion, a new operational model is assembled, largely based on available formulations of subsystems of the model. The model of the whole energy system used here is presented in full detail in [19]. It is not included in this paper to maintain the overview and to allow focusing on the results of the impact of PtG.

2.2. General model description

The energy system, consisting of the gas, electricity and CO_2 sector, is modelled as one single system, in which total operational costs (TOC) to meet the demand for each energy is minimised. The objective function is expressed by:

$$TOC = C_e + C_{PtG} + C_g \tag{1}$$

where C_e stands for the costs of electricity generation, including fuel costs (gas), start-up costs and carbon emission costs. The carbon emissions costs are applicable to the CO_2 that is not captured and emitted into the atmosphere. The operational costs for PtG plants are C_{PtG} and account for start-up costs, costs of input streams (CO_2, water, electricity) and output of pure oxygen. The gas costs are represented by C_g and account for gas bought on the spot market, used 'gas flexibility' for balancing the network and costs for using the seasonal storage.

The domestic demand for gas and electricity and renewable energy production profiles are assumed to be known a-priori and are exogenous to the model. Domestic gas and electricity demand here refer to the aggregated demand from the industrial, commercial, services and residential sectors.

In the gas system, the gas demand for the domestic and the (gas-fired) electric power generation sectors has to be met at all times by importing gas on the market and by producing renewable methane with the PtG plants. This is represented by the gas market clearing condition:[1]

$$\dot{G}_{im}(t) + \dot{G}_{PtG}(t) = \dot{G}_e(t) + \dot{G}_{dom}(t) + \dot{G}_{char}(t) + \dot{G}_{flex}(t) \tag{2}$$

where $\dot{G}_{im}$ represents the imported gas, bought on the gas market, $\dot{G}_e$ is the gas demand of gas-fired electric power plants, $\dot{G}_{dom}$ the domestic gas demand, $\dot{G}_{char}$ the gas charged to the storage facility —with negative values indicating

[1] Symbols with a dot represent flows. For gas this is expressed as a flow of primary energy. More specifically, for gas, we use the thermal energy that is represented by the higher heating value of the gas. (e.g., MW_{th} or GW_{th}).

a withdrawal from the storage, $\dot{G}_{PtG}$ the renewable methane produced by the PtG process and $\dot{G}_{flex}$ the hourly gas flexibility that is used. It is assumed that the gas market is one single spot market with a known and fixed supply curve, such that the instantaneous marginal gas price (MGC, in €$/MWh_{th}$) can be related linearly to the instantaneous gas import level:

$$MGC(t) = a + b\dot{G}_{im}(t) \tag{3}$$

Also, seasonal gas storage and gas flexibility are available, both with an associated cost, such that demand and imports do not have to be matched exactly for each time step. The gas flexibility costs are determined by the swing of the accumulated gas flexibility over one day (d):

$$C_{flex}(d) = c_{flex}\left\{\max(\sum_{d}\dot{G}_{flex}(t)) - \min(\sum_{d}\dot{G}_{flex}(t))\right\} \tag{4}$$

with c_{flex} the cost for a unit of gas flexibility. Gas flexibility allows an imbalance between gas import and demand for every time step, which is required due to cope with prediction errors of the gas demand and gas dynamics. However, it should be noted that the balancing of gas is not as critical as in the electric network where the demand and supply have to be balanced precisely at every moment, whereas the gas network has an inherent source of flexibility, the line-pack, and it usually provides enough flexibility to cope with the imbalances. Furthermore, fast-cycling storages can also be used to match supply and demand. Note that in some countries, LNG can also provide flexibility with a substantial storage and regasification capacity [26]. The actual dispatching of gas is an economic trade-off between using and paying for sources of flexibility ex-ante, which could include flexibility on the import market, and paying the gas transmission system operator (TSO) ex-post for the caused imbalances. A detailed discussion of this complex matter would lead too far here and we refer to [21] for more information. In this work, a simplified approach is used to include gas flexibility. The imbalance is accumulated over the time and forced to be zero at the end of each day—based on current practises in certain countries like e.g. Belgium [21]—and the costs for providing the required flexibility are related to the daily swing of the accumulated imbalance. The physical networks of gas and electricity are not modelled as such, but are implicitly part of the model through the gas supply curve and the demand constraints.

The domestic electricity demand ($\dot{E}_{dom}$) has to be covered at all times, this is represented by the electricity market clearing condition:

$$\dot{E}_{dom}(t) = \dot{E}_{wind}(t) + \dot{E}_{solar}(t) - \dot{E}_{curt}(t) - \dot{E}_{PtG}(t) + \dot{E}_{e}(t) \tag{5}$$

Electricity generation is provided by (PV) solar installations ($\dot{E}_{solar}$), wind turbines ($\dot{E}_{wind}$) and gas-fired power plants ($\dot{E}_{e}$). The gas-fired power plants (GFPP) create a primary link between the gas and the electricity sector. In this work, they are included with a unit commitment formulation in the model, subject to techno-economic operational constraints. Excess renewable electricity generation is curtailed ($\dot{E}_{curt}$) or used in the PtG process ($\dot{E}_{PtG}$). Short-term electricity storage like pumped hydro is not included in the model. Furthermore, no import and export of electricity is considered.

The gas-fired power plants are equipped with carbon capture (CC) plants which lower the electricity outputs from their respective power plants when the CC plants are turned on. If CO_2 emissions are not captured, emission costs have to be paid, according to the CO_2 emission price. CC plants provide a primary coupling between the electricity and the CO_2 sector. There is also an unlimited CO_2 storage facility incorporated. The physical CO_2 transport network is not part of the model. No distinction is made between short-term storage (buffering) and long-term storage (disposal).

Adding PtG to the model introduces new indirect linkages between the gas, electricity and carbon sector, as illustrated in Fig. 1. PtG consumes excess renewable electricity and captured CO_2, while producing renewable methane that is injected in the gas network where it mixes with natural gas. In this model, the use of renewable methane is not limited to power generation only, but also for domestic demand or storage in the seasonal storage facility. Also, note that the PtG process requires water for the electrolysis step and produces pure oxygen in the methanation step which can be marketed.

3. Case study

To assess the impact of PtG on the gas, electricity and CO_2 sector, we propose a case study reflecting an energy system with a high RES penetration and PtG. This hypothetical, future energy scenario is presented in Subsection 3.1, followed by a discussion of the dimensioning approach of the PtG capacity in the energy system (Subsection 3.2).

3.1. Case description

As there are too many uncertainties regarding a possible future energy system with high shares of RES, PtG and CC technologies, the energy system characteristics are based on the current gas and electricity system in Belgium where possible; otherwise, hypothetical characteristics are assumed.

The case consists of a hypothetical energy system with 100 % renewable electric energy provision on an annual energy basis, thus not taking into account the instantaneous matching of demand and supply. The renewable generation is provided by wind and solar, divided $50 - 50\,\%$.

Historic data of the domestic electricity demand, wind and (PV) solar production are taken from Belgian electricity transmission system operator (TSO) Elia. The annual demand is $77.8\,TWh_e$. The minimum demand is $5.58\,GW_e$ and the maximum is $12.8\,GW_e$. The wind and solar production profiles are both scaled to match 50 % of the annual electricity demand. As such, the installed capacity of wind turbines equals $16.8\,GW_e$ and $42.6\,GW_e$ for solar[2]. It is assumed that the operational costs, as well as curtailment costs, for RES generation are zero.

The backup of RES electricity generation is provided by gas-fired power plants (GFPP). The power plant characteristics are based on [27], and can be found in [19]. Each GFPP is equipped with CC. A high CO_2 emission price is assumed with 100 $€/ton_{CO_2}$. These costs are due when the produced CO_2 is

[2]There is large difference between the installed capacity of solar and wind because wind can generate at an equivalent of 28 % full load hours while solar generates only 11 %.

released into the atmosphere. These costs can be avoided by capturing the CO_2 by a CC plant.

Historic data of the domestic gas demand are taken from Belgian gas TSO Fluxys. The domestic demand corresponds to the demand for the industrial, commercial and residential sectors, excluding gas-fired electric power generation. The annual demand is approximately $140\,TWh_{th}$. The minimum demand is $5.4\,GW_{th}$ and the maximum $41\,GW_{th}$. The variation of the gas demand is largely related to the ambient temperature.

The modelled gas system is also based on information available from Fluxys about the Belgian gas network. Regarding the gas storage site, an operational capacity of $7\,TWh_{th}$ is taken. The maximal injection capacity is $3.25\,GW_{th}$ and the maximum withdrawal capacity is $6.25\,GW_{th}$, assumed independently of the actual status of the storage. As a simplification, the gas (dis)charging rates are assumed constant throughout the day. The storage costs are $5\,€/MWh_{th}$, based on gas storage tariff information made available by Fluxys [28]. The costs for providing flexibility are $2.5\,€/MWh_{th}$.

The entire gas supply is modelled as a single spot market. The supply costs of gas are assumed to have a linear relationship with the volume that is demanded and vary between $60\,€/MWh_{th}$ and $76\,€/MWh_{th}$. This range is based on projections in high gas price scenarios for the US in [1] and taking into account that gas in the EU may remain more expensive than US gas [29]. The spread on the gas prices is based on the spread that is currently seen in the market [29].

A hypothetical PtG plant is assumed, based on measured and projected characteristics of the PtG technology as documented in [11, 9, 22, 27, 23]. A 'black box' model of the PtG plants suffices for the research purposes in this paper.

Note that the model time step is 15 minutes to capture the intermittent behaviour of RES electricity and the modelling time interval is one year to include seasonal effects. Furthermore, the gas-fired power plants have been aggregated into one single plant in this case study to speed-up the computations.

Similarly, the PtG plants have been aggregated. The impact of the aggregation on the effects of PtG discussed in this work is limited, as shown in [19], while substantially speeding up the computations.

Domestic electric demand	Minimum	$5.58\,GW_e$
	Maximum	$12.8\,GW_e$
	Annual demand	$77.8\,GW_e$
Electricity generation	Wind (50 % energy-based)	$16.8\,GW_e$
	Solar PV (50 % energy-based)	$42.6\,GW_e$
	CCGT (backup generation)	$12.8\,GW_e$
CO_2	Emission price	$100\,€/ton$
Domestic gas demand	Minimum	$5.4\,GW_{th}$
	Maximum	$41\,GW_{th}$
	Annual demand	$140\,TWh_{th}$
Gas storage	Storage capacity	$7\,TWh_{th}$
	Storage injection capacity	$3.25\,GW_{th}$
	Storage withdrawal capacity	$6.25\,GW_{th}$
Gas market	Storage (injection) cost	$5\,€/MWh_{th}$
	Flexibility cost	$2.5\,€/MWh_{th}$
	Gas import price range	$60-76\,€/MWh_{th}$

Table 1: Characteristics of the case study

3.2. Determination of the installed power to gas capacity

This section provides a basic method for the determination of the PtG capacity in the energy system. It is out of scope to provide an accurate figure for the optimal capacity of PtG due to the numerous uncertainties related to, among others, investment costs, future energy and CO_2 market prices and characteristics of PtG plants. In order to determine a reasonable capacity of PtG plants in the system, the following, simplified dimensioning approach is used, based on the assumption that the produced methane must be competitive with natural gas.

Firstly, the production cost of renewable methane is estimated as a function of the number of operating hours (NOH). Via this cost curve, the required NOH is estimated to produce renewable methane at a cost that is competitive with natural gas on the import market. Secondly, the expected excess renewable electric generation is calculated. The load duration curve of this excess generation then gives the PtG capacity that corresponds to the required NOH. This approach is explained in more detail below.

3.2.1. Renewable methane production costs

The total production cost of a unit of renewable methane or *levelised* cost of methane is expressed as a function of the running hours of the plant, accounting for the assumed (annualised) investment and O&M costs, see Table 2, and the running costs of the plant (water, oxygen, CO_2 and electricity). No planning and construction costs are accounted for. CO_2 is assumed to be available for free because it is considered as a waste product of the electric sector (see results section). Pure oxygen (O_2) is available as a by-product of the methanation process and can be sold. A value of $70\,€/ton_{O_2}$ has been assumed [11]. An assessment of the sensitivity of the results to this assumption is shown in Fig. 2. The water needed to produce renewable methane is approximately $0.150\,m^3/MWh_{th}$. The cost of water is assumed at $0.7\,EUR/m^3$, which is almost negligible compared to other operational costs.

It is assumed that PtG only operates at times of excess renewable electricity generation and that this excess electricity is free. Currently, zero or even negative prices are seen in the market at moments of excess RES-based generation, but this can be mainly attributed to the priority feed-in of renewable electricity and support schemes. However, it is unclear how this will evolve with the growing share of renewables. Whether or not it is economically viable from the perspective of the owners of the RES installations to have a high capacity of RES installed is unclear. A sensitivity analysis of the renewable methane production costs to the input electricity costs is shown in Fig. 2.

	Electrolyser	Methaniser	Unit
Investment costs	750,000	50,000	€$/MW_{input}$
O&M costs	4	10	% of Inv. costs
Depreciation period	20	20	year
Intrest rate	7	7	%

Table 2: Assumed investment and O&M costs of an electrolyser and a methaniser, based on information available in [9] and [30]

The production costs of the renewable power methane are represented in Fig. 2 as a function of the plant operating hours and for different electricity costs and oxygen values. To analyse the sensitivity of the results, different electricity costs are indicated by the markers, going from $0 - 50$€$/MWh_e$, and different oxygen values are shown by the different line styles, ranging from $10 - 70$ €$/ton_{O2}$.

The number of operating hours is of major importance (Fig. 2). With the current gas prices, typically in the range of $25-40$€$/MWh_{th}$ [29], at least $2,000$ operating hours would be required to make competitive renewable methane when input electricity is free. If electricity costs 25 €$/MWh_e$, the minimum operating hours would increase to $4,000\,h$. For the high electricity prices, higher natural gas prices are required to make competitive renewable methane, even if the oxygen value is high and the NOH is high.

In this paper, it is assumed that the reference gas price is 60 €$/MWh_{th}$, based on future high price scenarios of [1] and information in [29]. This is indicated with a in Fig. 2. This reference gas price then leads to a minimum number of annual operating hours b of $1,600\,h$ with free electricity as an input and high-value oxygen as an output.

3.2.2. Determination of the power to gas capacity

The second step in the dimensioning analysis is relating the number of operating hours to the capacity of the PtG plants. This depends on the characteristics of the excess of renewable electricity generation. Fig. 3 shows the load

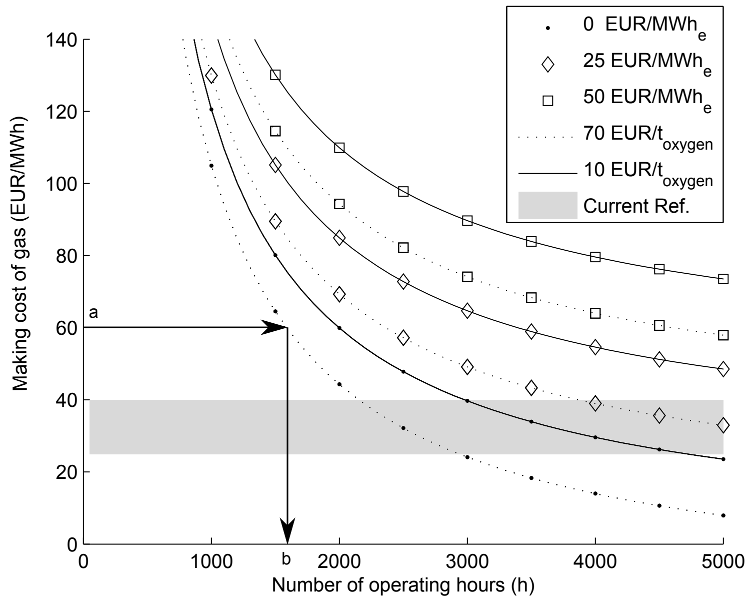


Figure 2: The total, or levelised, production cost of renewable power methane as a function of the plant operation hours. The production costs are shown for three different input electricity prices, indicated by the different markers. The production costs for different output oxygen values are indicated by the different line styles. In order to produce renewable methane that is competitive with natural gas on the market (assume, e.g., a), a certain minimum number of operating hours of the power to gas plants is required (b).

duration curves of the electric demand and the residual load, accounting for RES-based electricity generation.

The minimum required number of operating hours of the PtG plants (NOH), found from the analysis of the production costs of renewable methane, intersects with the residual load duration curve. The ordinate of this intersection determines the capacity of PtG plants that can be installed. In this particular case, about $7\,GW_e$ of PtG plants could be installed.

4. Results

Firstly, the effects of PtG are discussed per individual sector, being the (i) electric power sector, (ii) the gas sector and (iii) the CO_2 sector. This facilitates

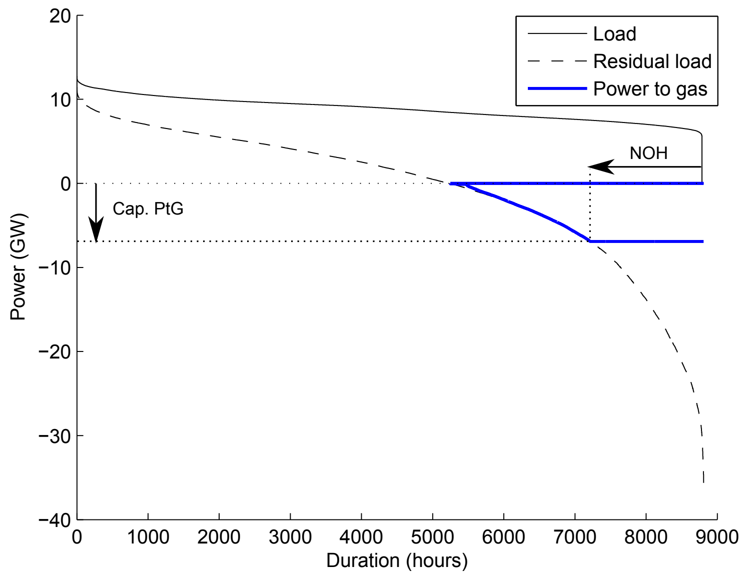


Figure 3: Determination of the capacity of the power to gas plants in the system. The minimum required number of operating hours (NOH) are found from the analysis of the production costs. The intersection of NOH with the residual electric load duration curve—taking into account RES generation—then gives the capacity of PtG, which is approximately $7\,GW_e$ in this case.

the understanding of the effects of PtG on the interactions between the sectors, discussed in the last part of the results. The effects per sector are discussed on two different time-scales: the long term (results on a full year) and the short term (results for one day). The short-term effects are all shown for one specific day with high wind and high solar production, as shown in Fig. 5.

The results will show that PtG leads, to some extent, to a shift of capacity and flexibility related issues in the electricity sector to the gas sector. Also, a downward pressure on the gas import prices due to PtG is observed. However, most effects of power to gas are secondary compared to the impact of RES-based electricity generation. Furthermore, the complex linkages between the different sectors introduced by PtG will be illustrated.

4.1. Impact of power to gas on the electricity sector

The long-term effects of PtG on the electric power sector are analysed by means of the load duration curves in Fig. 4. Subsequently, short-term effects are illustrated in Subsection 4.1.2.

4.1.1. Long-term effects on the electricity sector

Load duration curves of the domestic electric demand, gas-fired electric power generation, RES-based generation, electricity consumed by PtG and curtailment of RES are shown in Fig. 4. The areas circumscribed by the load duration curves then represent annual energies. Although the aim is a qualitative analysis, some figures are given below to facilitate the interpretation of the case study.

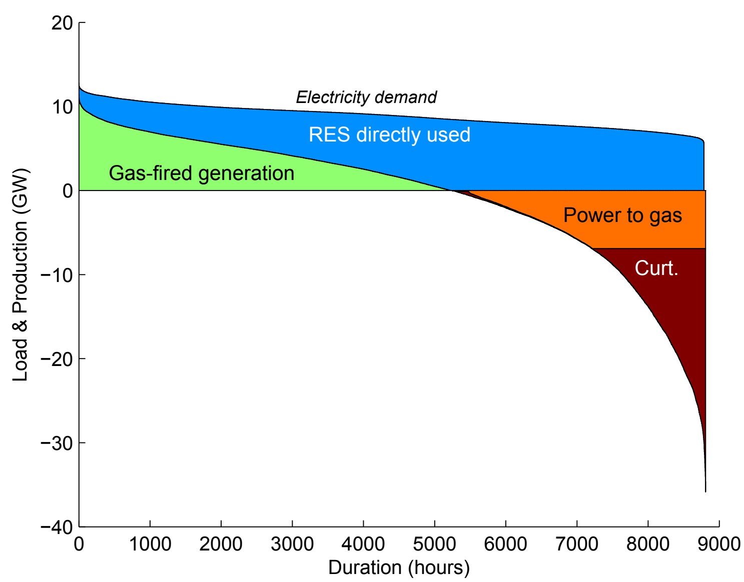


Figure 4: Load duration curves of the electric power load, generation, curtailment and demand for power to gas conversion.

The annual electricity demand is $77.8\,TWh_e$ of which $53.7\,TWh_e$ is directly provided by RES. An excess RES production of $16.7\,TWh_e$ is used in PtG plants and $13.4\,TWh_e$ is curtailed. The residual load, covered by gas-fired power plants, is $26.8\,TWh_e$ of which $2.68\,TWh_e$ has been used to generate electricity for the carbon capture (CC) plants. All produced CO_2 is captured due to the high emissions costs.

Although RES accounts for 100 % of the electric demand on an energy basis, the production and demand are not synchronous, resulting in a relatively high residual load coverage (31 %) by GFPPs. From the $30.1\,TWh_e$ of excess renewable energy, about 55 % can be used in PtG. This amount is limited because of the limited capacity of PtG[3]. While PtG leads to less curtailment, there is still 45 % of the excess renewable energy that needs to be curtailed, with a peak of approximately $30\,GW_e$.

Note that after the conversion of excess renewable electric power with PtG to methane (assumed efficiency 65 %), and re-conversion of that methane to electric power (assumed efficiency 50 %), $5.43\,TWh_e$ of the residual load could be covered indirectly by renewable power. This would increase the share of renewable electric power from 69 % to 76 %. However, as renewable methane mixes with natural gas, it cannot be said if this renewable methane is consumed by a gas-fired power plant, a residential or an industrial consumer.

Regarding the gas-fired power plants, the high amount of RES reduces the number of operating hours drastically while still a high installed capacity is required. In fact, enough capacity should be available in case there is no wind and no sun. This situation could lead to problems regarding the profitability of conventional generation capacity when the electricity prices are not reflecting the cost of electricity generation, which is often referred to as the *missing money problem*. In fact, the missing money problem is caused by the non-proper representation of scarcity in the electricity price.

PtG has no impact on the dispatch of electric power generation in this case study. Without PtG, the only difference in Fig. 4 would be that the PtG area

[3] Adding more PtG plants would not have been beneficial in this case from the viewpoint of the PtG plant owners because the number of operating hours would be too low to recuperate the investment costs.

would be curtailment. However, PtG could possibly have an impact on the individual dispatch of power plants in systems with a more complex generation mix and other cost assumptions. Also, the curtailment of RES could be different when electric power plants with other dynamic constraints are in the system.

4.1.2. Short-term effects on the electricity sector

The electricity dispatch on the specific day is shown in Fig. 5. During the night, wind power is not sufficient to cover the entire demand for electricity. During those moments, the residual load is covered by gas-fired power generation. Note that the backup generation has to be flexible to cope with the highly variable residual load.

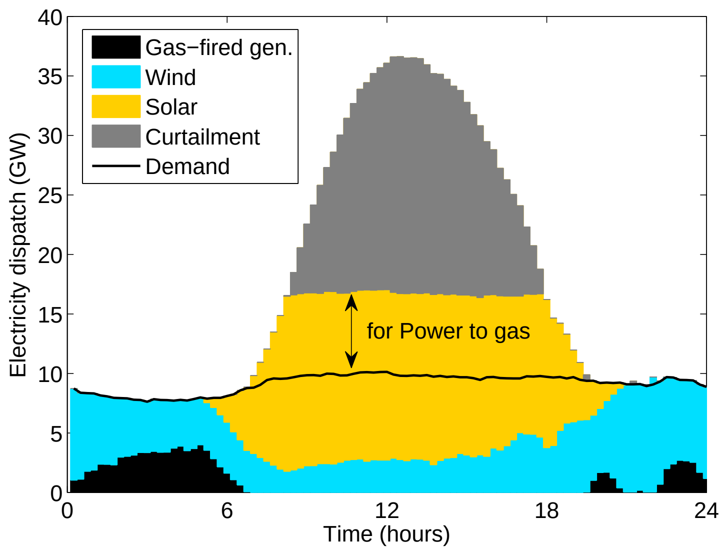


Figure 5: Electric power dispatch at the specific day. During the night, wind power alone is not sufficient to cover the demand and the residual load is covered by gas-fired generation. During the day, part of the excess power is converted in power to gas plants, the rest is curtailed.

During the day, part of the excess power is converted to renewable methane with the power to gas process, the rest is curtailed. Note that, although the figure suggests curtailment of solar power, this is only a representation. The actual curtailment could be a mix of wind and solar, depending on the curtailment costs, here assumed to be zero, and technical constraints.

Furthermore, the cost of generating an additional unit of electricity has been studied. The marginal electricity cost (MEC) of the specific day is shown in Fig. 6 where three cases are compared: (i) no renewable production, (ii) renewable production without PtG and (iii) both renewables and PtG. Whenever there is electricity generation by GFPPs, the MEC is set by the gas cost corrected for the power plants' efficiency. As stated before, the gas costs increase with the gas demand. As the gas demand is highest without RES, because of the high gas demand for power generation, the MEC will also be highest, as shown by the upper curve in Fig. 6. The marginal gas costs (MGC) are studied later on in Section 4.2.

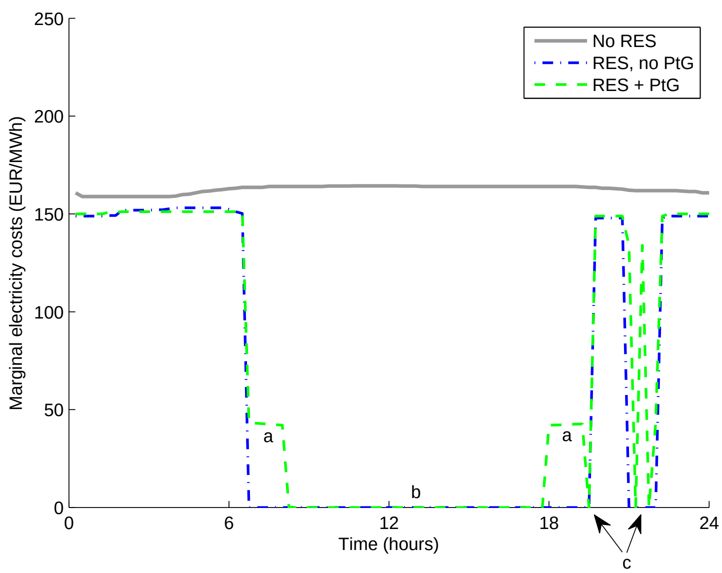


Figure 6: Marginal electricity costs (MEC) at the specific day. RES lowers the MEC because the gas demand is lower and subsequently gas is cheaper. During the day, solar production needs to be curtailed, hence, MEC is zero in the case study (b). With PtG present in the system, a side effect can be noticed (a). When PtG is the marginal unit, MEC are related to the value of renewable methane on the market. Operational effects like c are not relevant in this analysis.

During the day, the MEC goes to zero when there is RES curtailment, marked with b in Fig. 6, as curtailment is free of charge in this case study. When PtG is part of the system, another effect can be observed at the beginning (around 6:45 – 8:00) and the end (18:00 – 19:15) of the solar production period. PtG is then the marginal unit in the electricity dispatch. At such moments, the MEC is not zero, marked with a. This is because renewable methane is produced. Hence, a unit of extra electricity demand would result in less renewable methane, which has a certain market value. When the excess renewable power production exceeds the PtG capacity (8:15 – 17:45), however, the MEC falls to zero again because electric flexibility then corresponds to curtailment . Hence, when PtG is the marginal unit, MEC are coupled with the gas market. Other effects, marked with c, are related to operational constraints and are not relevant in this analysis.

4.1.3. Conclusions regarding the electricity sector

The main effect of PtG on the electric power sector is that the curtailment is lowered. However, still a large portion of renewable excess energy has to be curtailed, with a high peak power. Furthermore, when PtG is the marginal unit, the marginal electricity costs can be related to the value of renewable methane on the gas market. This is in fact an interaction effect between the different sectors and will be touched upon again in Section 4.4.

4.2. Impact of power to gas on the gas sector

The effects are analysed regarding the gas imports and gas flexibility for both the long-term and the short-term below. No significant effects were observed regarding the seasonal gas storage dispatch. Hence, this is not included in this analysis.

4.2.1. Long-term effects on the gas sector

The first long-term effect on the gas sector concerns the gas import level throughout the year. This is analysed by the load duration curve of the gas import in Fig. 7. The import levels throughout the year are lowered considerably by RES, and to a smaller extent by PtG.

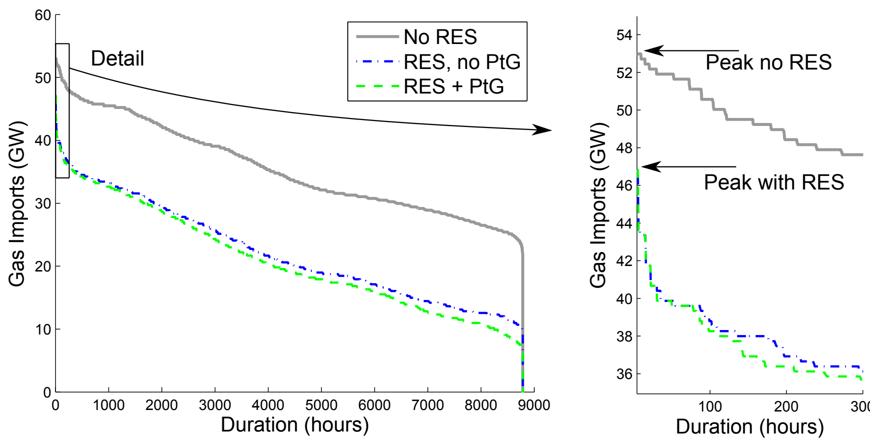


Figure 7: Load duration curves of the gas imports. The gas import level is lowered substantially by RES and even more by PtG. Still a high import capacity is needed, especially when taking the risk into account of no RES and no PtG production during cold, dark and windless periods.

455 An important observation is that still a high import capacity of the network is required, while the mean gas demand is generally much lower by RES. Taking into account that periods may occur without wind and sun, and with low temperatures, the import capacity should actually be the same with or without RES and PtG[4].

460 An important consequence of the reduced amounts of imported and transported gas—due to RES—is that there is more pressure on the investments of the gas infrastructure, and PtG further aggravates this situation, albeit to a

[4]Note that the peak import capacity should take into account both the import capacity by pipelines and the LNG import capacity. In the particular case of Belgium, LNG could provide a substantial peak shaving capacity. Also, gas from the seasonal storage can be used for balancing the imports and the gas demand. However, at the day when the peak gas demand occurs, the seasonal storage is already injecting gas at maximum injection capacity ($6.25\,GW_{th}$) in the case study.

lesser extent. In order to recuperate the gas infrastructure investment costs, the share of investment-related costs in the final gas cost should increase. This is in line with the findings of [14] where a lowered utilisation of gas transport capacity due to electricity generation by wind is stated to increase gas costs. This could be seen as a partial transfer of the capacity problem in the power sector where RES lower the number of plant operating hours so drastically that it becomes hard to maintain a profitable power generation. A correct representation of capacity costs in the final gas costs will thus be important, and this representation should not be hindered by regulations in order to not distort the gas sector.

Note that the term 'capacity' is used in a more general sense here. With capacity in the electricity sector, we refer to the generation capacity, while capacity in the gas sector refers to the import and transmission capacity of the gas network. Hence, a capacity issue should be seen as a problem that may complicate the recovery of investments, or hamper the investment in new infrastructure to provide the capacity that is required to deliver the demanded energy to consumers.

Also, the demand for gas flexibility is affected by PtG. The daily demands for gas flexibility throughout the year are put in a load duration diagram (Fig. 8). It can be seen that the demand for flexibility is generally increased substantially in the presence of RES. This is backed up by the findings of [14], which state an increased demand for flexibility due to electricity generation by wind turbines. With PtG in the system, the demand for flexibility is further increased. This is not a technical problem as long as the operational limits of the network are not exceeded. Furthermore, sufficient gas flexibility has to be available locally, as gas has a limited traveling speed.

4.2.2. Short-term effects on the gas sector

Firstly, the effects on the gas import profile are analysed on the specific day, as illustrated by Fig. 9a. As explained for the long-term effect on the gas sector, the impact of RES is larger than the impact of PtG. Recall from the

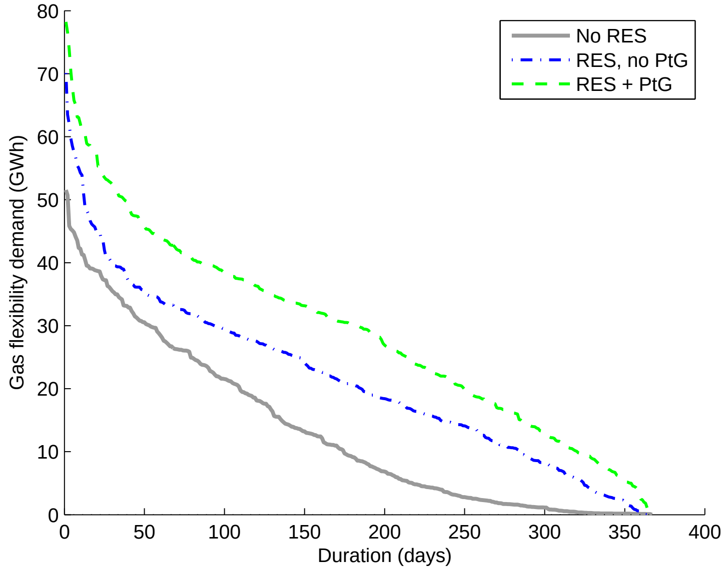
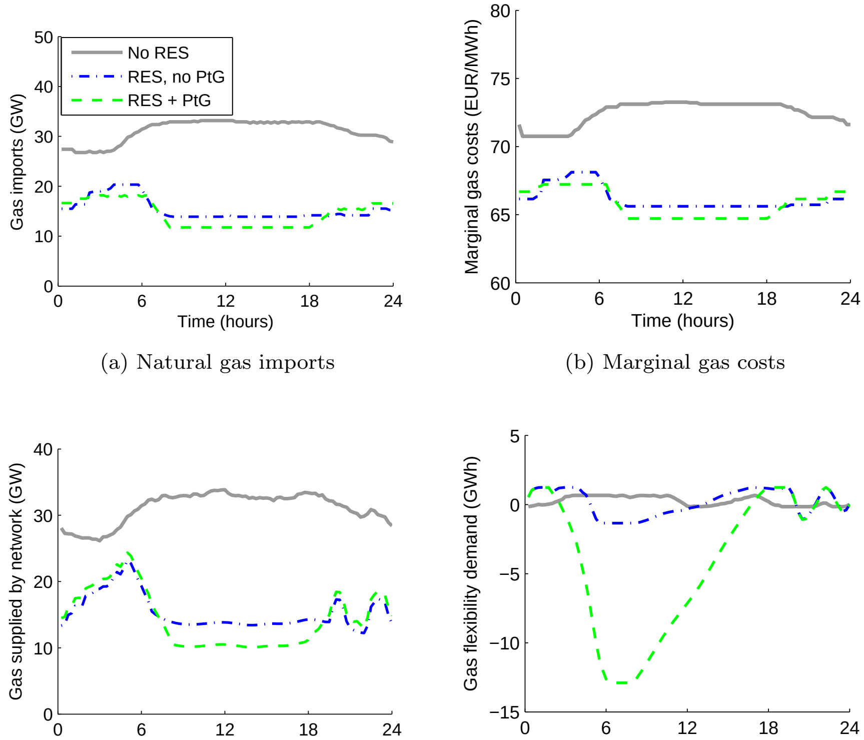


Figure 8: Load duration curves of the gas flexibility demand. RES increases the demand for flexibility, PtG further increases this demand for flexibility.

electricity generation dispatch (Fig. 5) that there is almost no gas demand for power plants this specific day because of the high RES production, except for a small part during the night. Hence, most imported gas in Fig. 9a is related to the domestic gas demand. PtG is operating during the daytime; this can be seen from the drop in the gas import profile.

It can be noted in Fig. 9a that there is an inverted peak of the import profile. Usually, in current gas systems, the peak occurs during the day. However, because of RES, and even more because of PtG, the import profile is higher during the night than during the day for this particular day. This inversion occurs generally during sunny days, such as the specific day shown here. During dark days, and depending on the actual wind generation profile, the peak occurs still mostly during the day. A similar situation has been observed in the Belgian electricity transmission network since 2012, where the lowest demand occurred for the first time during the day time in summer and this is related to PV



(a) Natural gas imports

(b) Marginal gas costs

(c) Natural gas supplied by network

(d) Accumulated gas flexibility

Figure 9: Short-term effects in the gas sector, depicted for the specific day.

electricity production [31].

Following, the marginal gas costs (MGC) are analysed in Fig. 9b. Recall that the MGC is directly related to the level of the gas import (see Fig. 9a) because of the assumed linear supply curve. RES-based electricity generation puts a downward pressure on gas import prices in the case study, and PtG strengthens this effect. In the studied case, the MGC is never below 60 €/MWh_{th}.

However, more severe situations have been observed in a simulation without a domestic gas demand (not illustrated here). Such simulation has shown moments where the MGC is zero. These moments occur during days without gas imports, which are related to low residential demand, high RES generation and PtG production. The marginal unit of gas is then related to PtG—which has zero operational costs in this model—instead of gas in the import market. Although it may not be realistic to assume zero operational costs for PtG, these results show that situations can occur where PtG sets the price on the gas market. If purely based on operational costs, and if input electricity is cheap at such a particular moment, renewable methane could be substantially cheaper than natural gas. This could possibly distort the natural gas market, a topic which merits further research.

At last, the usage of gas flexibility is analysed during the specific day. The flexibility is used to allow a difference between the natural gas import profile, as shown in Fig. 9a, and the profile of gas supplied by the network, as shown in Fig. 9c. The supplied gas accounts for natural gas supplied to the domestic sector, gas-fired power generation and seasonal storage; renewable methane is not part of this. Equivalently, the natural gas supplied by the gas network equals the natural gas imports minus the used hourly gas flexibility. An economic trade-off is made by the cost-minimising algorithm between flexibility costs in the gas network and costs on the import market which are related to the variability of the import profile[5]. The resulting accumulated flexibility of the specific day is shown in Fig. 9d. Recall that flexibility costs are related to the daily swing of the accumulated flexibility. For this particular day, RES has no major impact on the flexibility demand while PtG has a high impact. This is related to the higher variability of the gas demand profile with PtG than without PtG, as can be seen in Fig. 9c.

4.2.3. Conclusions regarding the gas sector

The variability in time of the gas demand and imports will increase due to RES-based electricity generation and PtG, possibly leading to more flexibil-

[5] Because of the quadratic relation between the gas import level and the total gas cost of a certain import level, it is more optimal to have a flat gas import profile throughout the time. Variability of the import level thus leads to more costs.

ity related costs. Furthermore, the capacity of the network will be used less efficiently as the average gas demand is lowered due to RES and to a lesser extent due to PtG, while the peak capacity of the gas system remains the same. This could lead to higher capacity related costs. This could lead to a partial transfer of the *missing money* problem from the electricity sector to the gas sector. It would thus be important that regulations do not hinder the correct representation of increased capacity and flexibility costs in the final gas price. Also, gas import prices may be lower as the demanded volumes are lower. In certain situations, such as systems with a very low domestic gas demand, renewable methane can set the price on the gas market at marginal production costs, which may possibly distort the gas market.

4.3. Impact of power to gas on the CO_2 sector

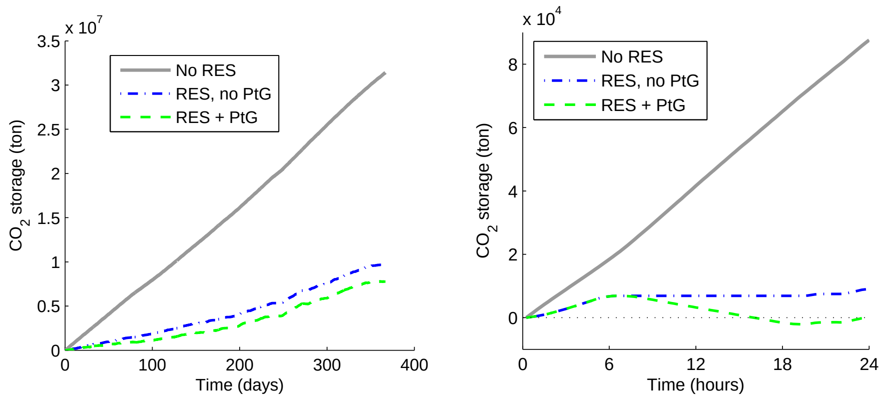
The CO_2 storage requirements are affected by PtG because of the CO_2 consumption in the PtG process. These effects are analysed in the sections below for both the long-term and the short-term.

In contrast, the CO_2 emissions are not affected by PtG in this case study. This is because the demand for gas-fired electricity generation stays the same, with or without PtG. The CO_2 capture rate is also the same, whether natural gas or renewable methane is used as the carbon contents and thus the emission costs are the same for both. Hence, the CO_2 production, capturing and emissions are equal with or without PtG. These observations apply for this particular studied system with only gas-fired electric power generation and may be different with a more complex fuel mix and/or other emission costs. However, the amount of CO_2 that will have to be disposed of is influenced by the presence of PtG, as will be seen further on.

Recall that emission costs are indeed applicable to renewable methane as the carbon is still of fossil origin. Not assigning emission costs to power generation with renewable methane would lead to emissions in the atmosphere of fossil carbon. These emissions would be delayed one step, though, as the carbon was captured in the previous step from power generation with natural gas and released in the next step when the renewable methane is burned. Hence, PtG should be seen as a way of recycling carbon and thereby lowering the need for fossil fuels.

4.3.1. Long-term effects on the CO_2 sector

Looking at the yearly results of the long-term CO_2 storage requirements in Fig. 10a, it can be seen that there is always an excess of CO_2. In other words, long-term storage is always needed in this case study. However, due to the consumption of CO_2 in the PtG process, less of the captured CO_2 will have to be disposed off. This could lower the long-term storage costs.



(a) Long-term storage of CO_2 (b) Storage of CO_2 on the specific day

Figure 10: CO_2 storage for the long-term (left) and the short-term (right). Long- and short-term effects of RES and PtG are that the need for permanent storing (disposing) of CO_2 are lowered. A short-term effect of PtG is the need for buffering.

4.3.2. Short-term effects on the CO_2 sector

The results of the specific day are depicted in Fig. 10b. Without RES, a large amount of CO_2 would need to be stored because all electric power generation would be carbon-based. With RES, CO_2 is only produced during the night because, during the day time, wind and solar production are more than enough to provide the demanded electricity. When PtG is present, the final storage requirement is even zero for this day. The final CO_2 storage requirement at the end of a day depends on the amount of RES-based generation. High RES-based generation lowers the CO_2 production from backup generation while (possibly) increasing the CO_2 demand for the PtG process because there could be more superfluous electricity generation. A (short-term) buffer will be necessary to cope with the unbalanced capture and usage of CO_2.

Following, the marginal cost of having available one extra unit of CO_2 (MCC) has been analysed. The MCC represents the value of one extra available unit of CO_2 for the whole energy system. At the specific day, the MCC is zero. This means that having an additional unit of CO_2 available does not have a cost nor does it have a value. This is because: (i) there is always an excess of CO_2 in the storage facility and (ii), there are no costs accounted for storing and transporting CO_2 in the model. The first effect is caused by the high emission costs, ensuring that all produced CO_2 is captured, and the high share of carbon-based backup generation. As the CO_2 demand of the PtG process is limited, an excess of stored CO_2 appears. More insights in the CO_2 value, and more specifically, the CO_2 market price, will be given in the next section regarding the inter-sector interactions affected by PtG.

Note that in this particular case study, the flow towards the long-term CO_2 storage is mainly unidirectional, as indicated in Fig. 10a; the only bidirectional flow is related to daily variations of the CO_2 consumption in the PtG process (Fig. 10b). Comparing to the natural gas network, daily variations and imbalances could be covered through the line-pack and/or small-scale storage. However, the mainly unidirectional flow towards the long-term storage is caused by the high share of carbon-based electricity generation. If the share of carbon-based electricity generation was much lower, seasonal balancing of CO_2 could possibly be needed, which cannot be provided by short-term storage such as line-pack and small-scale storages. In such cases, the long-term storage may need to be bidirectional. Moreover, if the physical state of the CO_2 is not gaseous but super-critical, it may be even more complicated to cope with daily variations and especially with bidirectional flow, as super-critical flow is incompressible. An analysis of different CO_2 transportation scenarios with respect to costs, capacity, distance, means of transportation and type of storage can be found in [32].

4.3.3. Conclusions regarding the CO_2 sector

PtG enables carbon recycling in the energy system because CO_2, captured from gas-fired power generation, is converted to renewable methane. The need for long-term CO_2 storage is lowered by RES and further by PtG. There is a need for short-term buffering to match the capture and consumption by PtG of CO_2. Seasonal balancing of CO_2 may be required. The required CO_2 network may thus become as complex as a natural gas network, depending on the actual situation of the energy system, such as, e.g., the locations of carbon based power generation, PtG plants and share of RES.

4.4. Impact of power to gas on the interactions between the different sectors

The effects of PtG on the interactions between the gas, electricity, gas and carbon sector are described below. Firstly, possible electricity-gas sector feedback loops are discussed. Secondly, the complex dependencies between different sectors through the CO_2, required for the PtG process, are identified and illustrated.

4.4.1. Electricity-gas feedback loops

The interactions between the gas and the electricity system are affected by PtG. PtG allows storing excess renewable electricity as renewable methane in the gas network. However, as such, some issues from the electric power sector are partially passed on to the gas sector. As indicated in Section 4.2, flexibility and capacity related costs in the gas sector may increase because of RES and also by PtG. In turn, these costs can be passed on again to the electricity sector through the gas-fired power generation, which can be seen as a feedback effect through PtG.

Furthermore, when RES-based electricity generation is such that PtG is the marginal unit, the marginal electricity price can be related to the value of renewable methane on the gas market.

4.4.2. Intersector dependencies through CO_2

PtG introduces complex interdependencies between different sectors through the CO_2 that is required in the process. These linkages are illustrated below for different situations, depending on (i) the 'potential availability' of CO_2 and (ii) the 'willingness' of electric power plants to capture CO_2 emissions. The 'potential availability' of CO_2 refers to the amount of CO_2 that is produced and *could* be captured at (carbon-based) electric power plants compared to the amount of CO_2 that is required in the PtG process. Thus, CO_2 can *potentially* be sufficiently available for the PtG process or not. The 'willingness' to capture CO_2 depends on the economic trade-off between increased operational (fuel) costs to power the carbon capturing plants compared to the costs of CO_2 emissions. Four different combinations can be made and these are discussed below, illustrating the complex linkages between all sectors that can be introduced by CO_2.

The first combination corresponds to the case study: (i) there is a willingness of electric power plant owners to capture as much CO_2 as possible because the emission cost is high and (ii) there is a high availability of CO_2 because the high share of carbon-based electric power generation compared to the CO_2 demand for the PtG process. Hence, there is an excess of CO_2. The analysis of the MCC in Section 4.3.2 showed indeed that the value of an additional unit of CO_2 is zero in this case. Note that the CO_2 price is not the same as the CO_2 emission cost; the CO_2 price is the price of CO_2 on the 'CO_2 market'. However, the CO_2 price will be linked to the CO_2 emissions cost, as the emission cost determines the willingness to capture CO_2.

The second combination corresponds to (i) a willingness to capture CO_2 but (ii) a low availability of CO_2. The low availability occurs e.g. if there is little carbon-based electricity generation. The value of CO_2 for the whole system is then high. This was also found in a simulation of such situation; the MCC at an example instant corresponds to -383 €/ton, meaning that the whole energy system would benefit from an additional unit of available CO_2. The value of CO_2 is then indirectly linked to the value of renewable methane on the gas market (MGC = 69 €/MWh_{th}) through the conversion in the PtG process (0.18 tons of CO_2 per MWh of gas).

The third combination corresponds to (i) no willingness to capture CO_2 due to a low emission cost but (ii) a high potential availability of CO_2. In such case, CO_2 can still have a positive value for the whole energy system, but the capturing of CO_2 should be compensated for. A positive CO_2 price can be expected then; i.e., the PtG plant owners would pay a certain price for CO_2 such that the electric power plant owners are compensated for the additional costs that carbon capturing brings along. As the price of CO_2 then depends on the additional costs for carbon capturing, it will depend on the carbon capturing plant characteristics, electric power plant characteristics and input fuel costs (natural gas in the case study).

The fourth combination corresponds to (i) no willingness to capture CO_2 and (ii) a low potential availability of CO_2. In such case, there is not enough CO_2 to provide PtG with all demanded CO_2, even if the electric power plants are compensated for the use of carbon capturing plants through a CO_2 price. The value of CO_2 for the whole energy system is, as in combination two, related to the natural gas market where the import of an amount of natural gas could be avoided. In fact, it can be linked to the opportunity cost of saving natural gas.

In conclusion, PtG introduces complex linkages between all sectors through the CO_2 that is required in the process. The linkages illustrated here depend on the availability of CO_2 in the carbon-based electric power generating sector compared to the CO_2 demand for PtG. Hence, this is also dependent on the characteristics of the renewable power generation, as it affects both carbon-based backup generation and PtG operation. The interactions also depend on the CO_2 emission cost. Furthermore, linkages depend on carbon capturing characteristics, power plant characteristics, PtG plant characteristics and the natural gas market. Note that this analysis does not take into account CO_2 transport, buffering and storage and that by taking this into account, the situation could become even more complex.

5. Summary and conclusions

The power to gas concept is argued to be an interesting method for storing surplus renewable energy in the form of renewable hydrogen or methane. The renewable methane can easily be stored in the gas system, which has a large capacity compared to electrical storage. However, while the natural gas infrastructure is generally assumed to be robust, it has not been analysed what the effects of power to gas are on the gas system. Moreover, power to gas introduces new couplings between the gas, the electricity and the CO_2 sectors and it is relevant to study these effects.

In this paper, it has been demonstrated via an operational model that power to gas indeed affects the gas, the electric power and the CO_2 sector, and even the interactions between these sectors.

A case study with high renewable energy shares and gas-fired backup electricity generation has been studied. Even though the results are limited to the single case analysed, subject to simplifications and assumptions regarding a possible future scenario, certain interesting effects can be illustrated by the model.

The main findings are that:

In the gas sector The known capacity and flexibility issues, and downward pressure on the energy prices in the electricity sector due to a high share of intermittent renewable electricity generation are partially passed on to the gas sector. Renewable energy reduces the average demand for gas in power generation, while still a high transport and import capacity of the gas network is needed. This may put more pressure on the gas infrastructure investments. This effect is further aggravated in the presence of power to gas.

Furthermore, the results indicate that more flexibility will be needed in the gas network with power to gas. Hence, power to gas could increase capacity and flexibility related costs in the final gas price. On the other hand, gas import prices could be lowered by power to gas. An extreme case—with low domestic gas demand—even shows renewable methane injection at marginal production costs, which could be well below the market price of natural gas, possibly distorting the natural gas market.

In the electricity sector Power to gas may set the marginal electricity costs when power to gas is the marginal unit in the electricity market. As such, the power to gas conversion may increase the value of renewable electricity generation.

In the CO_2 sector Power to gas lowers the need for the disposal of CO_2 in long-term storage sites. Therefore, it can be concluded that power to gas would lower the associated storage costs. On the other hand, short-term buffering is needed to match CO_2 capture and usage in the power to gas process. Two-directional flow may be required from the long-term CO_2 storage to the power to gas plants, depending on the generation mix and the installed capacity of power to gas plants. The required transport, storage and balancing of CO_2 might make a CO_2 network as complex as a natural gas network.

On the interactions The value of CO_2 for the whole energy system depends on characteristics of the different sectors, such as, but not limited to, the gas price, the emission price, carbon capturing plant characteristics, power to gas plant characteristics and the amount of carbon-based electricity generation compared to the installed capacity of power to gas plants. Hence, the complexity and the number of linkages between the different sectors have significantly increased by the presence of power to gas.

These effects should be kept in mind when designing a system with a high share of renewable energy and power to gas. The impact of power to gas seems to be lower than the impact of intermittent renewable energy, though, except in the case of flexibility.

It should be studied in further work if the design of the system is compatible with power to gas. In the case study presented in this paper, the implemented gas import model is a spot market. However, current gas contracts are mostly long-term contracts. In 2013, approximately 60 % of the total European gas supply was long-term contracted with an oil-linked formula [33]. There is a trend, though, towards more gas trading on the spot market. The results in this work suggest that more import flexibility will be needed with a higher share of renewables and even more when power to gas comes in the system. Therefore, high shares of RES and PtG may not be compatible with a highly long-term contract based gas supply.

Furthermore, the case study was limited in this work to gas-fired power plants. However, the model also allows to investigate more complex generation mixes, which may also lead to interesting results.

Also, the model designed to operationally optimise the whole energy system at once. It would be interesting, however, to see how different actors in the system react to power to gas.

Further analysis is needed regarding the sensitivity to the assumed parameters of the model, such as the amount of wind and solar in the system and the operational parameters. Also, the effect of the dimensioning of the power to gas plants needs to be studied further.

The impact on physical gas and electricity networks could be analysed by using the simulation data as input to the network models, or the networks could be integrated in the model itself.

It would also be interesting to study the impact of the unpredictabilities with a stochastic model. PtG could provide short-term flexibility in the electric power sector.

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